TECHNICAL REVIEW DOCUMENT
for
RENEWAL of OPERATING PERMIT 96OPDE134

Public Service Company, Zuni Station
Denver County
Source ID 0310007

Prepared by Jacqueline Joyce
August 2003
Revised November 24, 2003
Revised March 11, 2004 to address comments made by EPA during EPA's 45-day review period

I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed operating permit proposed for this site. The original Operating Permit was issued July 1, 1998 and expires on July 1, 2003. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted June 12, 2002, comments on the draft permit and technical review document received November 19, 2003, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

This source is classified as an electric services facility under Standard Industrial

Classification 4911. This facility consists of three steam boilers (Units 1A, 1B, & 2) that are fueled primarily by natural gas, although No. 6 fuel oil is used as a back-up fuel. Typically these boilers provide steam to the downtown Denver area, however, during peak operating periods the turbines are brought on line. Boilers 1A and 1B serve a common turbine that is rated at 45 gross MW (GMW) and boiler 2 supports a turbine rated at 76 GMW. In addition, there are cold cleaner solvent vats at this facility that are subject to requirements in Colorado Regulation No. 7 and are therefore included in Section II of the permit.

Based on the information available to the Division and provided by the applicant, it appears that no modifications to these significant emission units has occurred since the original issuance of the operating permit. In addition, the list of insignificant activities has not changed since the original permit issuance.

Note that none of the boilers are equipped with a control device and therefore the Compliance Assurance Monitoring (CAM) requirements to not apply to these units.

The facility is located at 1335 Zuni Street in Denver County, within the Denver metro area. The Denver metro area is classified as attainment/maintenance for particulate matter less than 10 microns (PM_{10}), ozone and carbon monoxide and attainment for all other criteria pollutants. Under that classification, all SIP-approved requirements for PM_{10}, VOC and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to update actual emissions and to more appropriately identify the potential to emit (PTE). The PTE in the original TRD was based on emission factors and 8,760 hours per year of operation at the maximum design rate and did not take into account any regulatory emission limits, such as the Reg 1 PM and SO_2 emission limitations. In addition, since there has been a change in emission factors, for those pollutants whose PTE is based on emission factors, the PTE has been adjusted to reflect the updated emission factors. Emissions (in tons per year) at the facility are as follows:

Pollutant	Potential to Emit – 100% Natural Gas	Potential to Emit – 100% No. 6 Fuel Oil	Actual Emissions – Combination[3]
PM[1]	782.2	782.2	1.3
PM_{10}	782.2	555.7	1.3
SO_2[2]	4.5	6,657	0.8
NO_X	2,069	2,367	98.6
CO	620.6	251.9	18.3
VOC	40.6	38.2	0.8

Pollutant	Potential to Emit – 100% Natural Gas	Potential to Emit – 100% No. 6 Fuel Oil	Actual Emissions – Combination[3]
HAPS	13.9	6.6	below de minimis

[1]PTE, when burning any fuel, is based on the Reg 1 PM limit (0.102 lbs/mmBtu for Unit 1A, 0.126 lbs/mmBtu for Unit 1B and 0.1 lbs/mmBtu for Unit 2) x design heat rate x 8760 hrs/yr. Note that for using No. 6 fuel oil, PM_{10} is determined to be 71% of PM and for natural gas, all PM is determined to be PM_{10}.
[2]PTE, when burning No. 6 fuel oil, based on the Reg 1 SO_2 limit (0.8 lbs/mmBtu for Units 1A and 2 and 1.5 lbs/mmBtu for Unit 1B) x design heat rate x 8760 hrs/yr.
[3]Actual emissions identified in the table are based on natural gas consumption only, although the boilers may burn either natural gas or No. 6 fuel oil.

Potential to emit for the boilers is based on the information identified in the table and the maximum hourly fuel consumption rate, AP-42 emission factors and 8760 hrs/yr of operation. Actual emissions are based on the Division’s 2002 inventory.

Based on AP-42 emission factors, the Zuni facility has the potential to emit of 13.3 tons/yr of hexane. Therefore, the Zuni facility is a major source for HAPS. The facility is not subject to the case-by-case MACT requirements in Section 112(j) of the Clean Air Act, since the facility has no emissions units covered by the source categories for which EPA failed to promulgate standards by the specified deadline. However, a future MACT standard is being developed for utility boilers, which may apply to emission units at this facility in the future.

III. Discussion of Modifications Made

Source Requested Modifications

The source’s requested modifications identified in the renewal application were addressed as follows:

Page following cover page

The Responsible Official and the Permit Contact was changed as requested by the source.

Section 1, Condition 2.1, Page 2

The source requested that the alternative operating scenario for burning different fuels (i.e., natural gas, No. 6 fuel oil and combination) be removed from the permit, since the boilers were designed and built with the capability to burn both natural gas and fuel oil. Since these units were never restricted from burning these fuels by permit and since the operating permit listed scenarios for burning natural gas, No. 6 fuel oil and combination, the Division agrees that the alternative operating scenario language for burning various fuels is not necessary. Therefore, the only alternative operating scenario included in the renewal permit is the scenario for boiler chemical cleaning solutions.

Section II, Conditions 1.1, 2.1, 4.1, 5.1 ,7.1 and 8.1, Pages 4,7,16,19,27 and 30

The source requested that since AP-42 emission factors have been revised that the permit be revised to reflect the new AP-42 emission factors. The Division has made this change as requested. The new emission factors that will be included in the renewal permit are as follows:

Pollutant	Emission Factor	
	Natural Gas (lbs/mmSCF)	No. 6 Fuel Oil (lbs/mgal)[1]
PM	1.9	9.19S + 3.22
PM_{10}	1.9	0.71x PM
SO_2	CMS	CMS/162.7S
NO_X	CMS	CMS
VOC	5.5	0.76
CO	84	5

[1]S = weight percent sulfur in the fuel

Annual emissions of NO_X and SO_2 shall be estimated using the continuous monitoring systems required by 40 CFR Part 75.

For Natural Gas, the emission factors are from AP-42, Section 1.4, dated 3/98), Tables 1.4-1 (large (> 100 mmBtu/hr), wall-fired, uncontrolled, pre-NSPS units) and 1.4-2.

For fuel-oil fired, the emission factors are from AP-42, Section 1.3, dated 9/98, Tables 1.3-2 (large (> 100 mmBtu/hr), normal firing, No. 6 fuel oil), 1.3-4 (uncontrolled) and 1.3-3 (utility boilers, normal firing, No. 6 fuel oil).

Note that the Division estimated potential HAP emissions using the following AP-42 emission factors from Tables 1.4-3 and -4 (natural gas fired) and Tables 1.3-9 and -11 (fuel oil fired).

Pollutant	Emission Factor	
	Natural Gas (lbs/mmSCF)	No. 6 Fuel Oil (lbs/mgal)
Formaldehyde	7.5×10^{-2}	3.3×10^{-2}
Benzene	2.1×10^{-3}	2.14×10^{-4}
Naphthalene	6.1×10^{-4}	1.13×10^{-3}
Toluene	3.4×10^{-3}	6.2×10^{-3}
Hexane	1.8	N/A
Nickel	2.1×10^{-3}	8.46×10^{-2}

Pollutant	Emission Factor	
	Natural Gas (lbs/mmSCF)	No. 6 Fuel Oil (lbs/mgal)
Arsenic	2.0×10^{-4}	1.32×10^{-3}
Antimony	N/A	5.25×10^{-3}

In addition, in their comments on the draft permit, received November 19, 2003, the source indicated that the language addressing annual NO_X emissions is inconsistent with the requirements in 40 CFR Part 75. The source requested that the annual NO_X emissions be determined based on the total sum of the year's hourly NO_X ton values. The Division will revise the permit as requested by the source.

Section II, Conditions 1.4, 1.5, 4.4, 4.5, 7.4 and 7.5, Pages 5, 7 and 28

The monitoring requirements for opacity when burning natural gas require recordkeeping of visible emissions and method 9 observations when visible emissions persist for more than 15 minutes. The Division had included these monitoring requirements in the original permit, since, at the time, one of the boilers was having opacity problems when burning natural gas. Typically the Division just indicates in the permit that for sources burning natural gas as fuel, that compliance with the opacity requirements is presumed in the absence of credible evidence to the contrary. In their renewal application, the source indicated that they have taken measures to address the opacity problems when burning natural gas. They have installed new burner tips to provide better O_2 mixing, installed restriction plates in the burner wind boxes to concentrate the air at the flame, installed cameras to monitor the stack, established new set-points for the O_2 alarms and provided additional training to operators. Typically this facility is inspected by Denver county and the Division asked Denver county to provide input on whether the opacity problems appear to have been adequately addressed. Denver county indicated that have not seen any problems with visible emissions for some time. Therefore, as requested by the source, the Division will revise the opacity monitoring language when burning natural gas to indicate that in the absence of credible evidence to the contrary, compliance with the standard is presumed, whenever natural gas is used as fuel. It should be noted that if the Division determines at a later date that opacity problems still exist at the Zuni facility, the Division will either revise the permit prior to issuance or reopen the permit to include more stringent monitoring requirements.

Other Modifications

In addition to the modifications requested by the source, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepencies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Zuni Renewal Operating Permit with the source's requested modifications. These changes are as follows:

<u>Page following Cover Page</u>

Clarified dates for monitoring and compliance periods, i.e. changed "July - December" to "July 1 – December 31".

Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on the permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

The citation (above "issued to" and "plant site location") on the page following the cover page provides the incorrect title for the state act. The title will be changed from "Colorado Air Quality Control Act" to "Colorado Air Pollution Prevention and Control Act". In addition, the reference to specific dates has also been removed.

Added language specifying that the semi-annual reports and compliance certifications are due in the Division's office and that postmarks cannot be used for purposes of determining the timely receipt of such reports/certifications.

<u>Section I - General Activities and Summary</u>

The language in Condition 1.1 was changed to reflect the attainment/non-attainment status of the Denver metro area and to indicate that cold cleaner solvent vats have been included in Section II of the permit.

The language in Condition 1.3 was changed based on comments made by EPA on other Operating Permits.

Condition 1.4 was split into two conditions, one addresses enforceability (Condition 1.4) and the other recordkeeping requirements (Condition 1.5).

In Condition 1.4, Conditions 13 and 17 were renumbered to 14 and 18 and Condition 21 in Condition 1.5 was renumbered to 22 due to the addition of a new general condition.

In addition, based on comments made by EPA during their 45-day review period, Condition 1.4 was revised to add General Condition 3.g (Common Provisions, Affirmative Defense) as a state-only condition.

Removed the language in Condition 1.6 addressing Non-Attainment Area major New Source Review (NSR). Since the Denver metro area is no longer a non-attainment area, these provisions do not apply. In addition, this condition was moved to the “new” section 3 for PSD (see below).

The alternative operating scenario language (Condition 2.1) for boiler chemical cleaning was revised to be more consistent with the language in other power plant permits issued to PSCo.

Based on comments made by EPA on another operating permit, the phrase “Based on the information provided by the applicant” was added to the beginning of Condition 3.1 (Accidental Release Prevention Program, 112(r)).

Added a “new” Section 3 for Prevention of Significant Deterioration and moved Condition 1.6 into this section as Condition 3.2.

Added a “new” Section 5 for compliance assurance monitoring (CAM), note that no emission units are subject to CAM.

<u>Section II - Specific Permit Terms</u>

Section II.1 thru 9: Boilers

The technical review document for the original operating permit issued for this facility indicated that since the boilers were operated as peaking units, they were not equipped with NO_X continuous emission monitoring systems but were using the provisions in 40 CFR Part 75 Appendix E to monitor NO_X emissions. However, two of the boilers were operated at such a level, that they were no longer considered peaking units. Therefore, NO_X CEMS were installed on Units 1A and 1B. Note that no revisions to the permit are necessary, since NO_X emissions will still be monitored using the continuous monitoring systems required by 40 CFR Part 75, as currently specified in the permit.

Since there is not a significant difference in the applicable requirements for the various boilers, all units were included in one table/section. There is one section for natural gas burning (Section II.1), one for No. 6 fuel oil burning (Section II.2) and one for combined fuel burning (Section II.3).

The conditions in the section for combined fuel burning were removed and replaced with language indicating that the permittee should follow the most stringent monitoring requirements when a combination of fuels is burned.

Natural Gas Conditions:

The format for the equation in Condition 1.1 was revised. In addition, minor language changes were made to this condition.

Minor language changes were made to Condition 1.2. In addition, removed the language in this condition regarding co-firing with fuel oil.

The monitoring language in Condition 1.3 was changed to "In the absence of credible evidence to the contrary, compliance with the particulate matter standards shall be presumed whenever natural gas is use as fuel in these boilers." In addition, minor language changes were made to this condition.

The language for the opacity conditions (Conditions 1.4 and 1.5, both text and table) was revised to more closely match the language in the regulation.

Corrected the citation in Condition 1.6 (Acid Rain Requirements) and removed the requirement to submit copies of the quarterly certifications to the Division.

No. 6 Fuel Oil Conditions:

The format for the equation in Condition 2.1 was revised. Added language specifying the weight percent sulfur to be used in the PM emission calculations. In addition, other minor language changes were made to this condition.

Minor language changes were made to Condition 2.2.

Revised the language in Condition 2.3 and added an equation to make the monitoring method clearer and more like the permit issued for PSCo's Denver Steam facility.

Minor language changes were made to Condition 2.4.

Revised the format and language in Condition 2.5. Added the reporting requirements from Reg 1, Section IV.I, which were not previously included in the permit. In addition, the requirement in Reg 1, Section IV.H was streamlined in favor of the 5 year recordkeeping requirements in the general conditions. Note that the recordkeeping requirement was also not previously included in the permit.

The language in Condition 2.7 regarding the Reg 1 two yr recordkeeping requirement being superceded by the 5 yr recordkeeping requirement in the general conditions was removed. The 2 yr recordkeeping requirement was streamlined out of the permit.

The language for the opacity conditions (Conditions 2.8 and 2.9, both text and table) was revised to more closely match the language in the regulation.

Conditions 2.8 and 2.9 were combined into one condition. Revised the format and added language indicating that a violation of the opacity limit is presumed to last from the time a Method 9 showing non-compliance is read until a Method 9 reading showing compliance is read.

Corrected the citation in Condition 2.10 (Acid Rain Requirements) and removed the requirement to submit copies of the quarterly certifications to the Division.

Section II.10: Safety Kleen Cold Cleaner Solvent Vats

When the original permit was issued for this facility, cold cleaner solvent vats that met the definition of small remote reservoir units could take the APEN exemption even though the solvent vats were subject to specific requirements in Reg 7 and were presumed to comply with the requirements in Reg 7. Revisions were made to the "catch-all" provisions in Regulation No. 3 and those revisions became effective on December 30, 2002. With these revisions, an emission unit that is subject to specific Regulation No. 7 requirements can take the APEN and construction permit exemptions and the specific APEN exemption for small remote reservoir units was removed. However, an emission unit that is subject to specific Regulation No. 7 requirements cannot be considered an insignificant activity. Therefore Section II.10 were revised to remove the reference to the small remote reservoir unit APEN exemption.

In addition, the permit was revised to add the Reg 7 transfer and storage of waste/used solvents requirements, since this requirement was not previously included in this permit.

<u>Section III – Acid Rain Permit</u>

The designated representative and the alternate designated representative were revised.

The years in the tables (Section 2) were changed to reflect the permit term for the renewal. In addition, removed the statement in Section 2 indicating that the source was not required to hold allowances until the year 2000.

Revised the language in Section 3 to reflect changes to the underlying requirements (40 CFR Part 72 § 72.9). These changes are very minor.

Removed the requirement to submit a copy of the quarterly compliance certifications to the Division. The Division has determined that submittal of the annual certification is all that is necessary to monitor compliance with the Acid Rain Requirements.

Removed the requirements to submit excess opacity reports. Neither 40 CFR Part 75 or Colorado Regulation No. 1 require these units to be equipped with continuous opacity monitoring systems (COMS) and the opacity records on which the reports are to be based (per §§ 75.54(f) and 75.57(f)) are based on COMS data. Therefore, since these units do not have COMS, submittal of the excess opacity information is not required.

Section III – Permit Shield

The citation for the permit shield is incorrect. The reference to Part A, Section I.B.43 should be Part A, Section I.B.44 and the reference to Part C, Section XIII should be Part C, Section XIII.B.

The title for Section 1 was changed from "Specific Conditions" to "Specific Non-Applicable Requirements" and a new section 3 was added for subsumed (streamlined) conditions. Note that the only streamlined conditions are the requirement to keep records for 2 years (Colorado Regulation No. 1, Sections IV.H and VIII.C), which were streamlined out in favor of the 5 year retention requirement by Colorado Regulation No. 3, Part C, Section V.C.6 (general condition No. 22.b and c). Note that the permit previously contained (In Condition 2.7) language indicating that the Reg 1, Section VIII.C requirement to retain records for 2 years was superceded by the requirement to retain records for 5 years.

Based on comments made by EPA on another permit, the following statements were added after the introductory sentence in Section 1 "This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modification or reconstruction on which construction commenced prior to permit issuance."

Based on comments made by EPA on another permit, the following phrase was added to the beginning of the introductory sentence "Based upon the information available to the Division and supplied by the applicant".

Based on comments made by EPA on another permit, the language in the justification (Section 1 - table) regarding modifications for Reg 6, Part B, Section II and Reg 6, Part A, Subparts D, Da, Db and Dc were removed. The shield for these requirements as non-applicable is based on the construction date of the boilers.

In addition, based on comments made by EPA on another permit, the Division revised the justification for the permit shield for PSD review requirements to remove the language regarding modifications. All equipment was installed prior to August 19, 1971. Therefore the shield for the PSD review requirements as non-applicable is based on the construction date of the facility.

Section IV - General Conditions

Added an "and" between the Reg 3 and C.R.S. citations in General Condition 3 (compliance requirements).

Added language from the Common Provisions (new condition 3). With this change the reference to “21.d” in Condition 20 (prompt deviation reporting) will be changed to “22.d”, since the general conditions are renumbered with the addition of the Common Provisions. Note that based on EPA’s comments during their 45-day review period, added language indicating that affirmative defense provisions are state-only until approved by EPA.

The citation in General Condition 7 (fees) was changed to cite the Colorado Revised Statue. In addition, any specific identification of a fee (i.e. $100 APEN fee) or citation of Reg 3 was removed and replaced with the language “…in accordance with the provisions of C.R.S. [appropriate citation].”

The citation in General Condition 13 (odor) was corrected. In addition, the phrase “Part A” was added to the citation for Condition 13 (odor). Colorado Regulation No. 2 was revised and a Part B was added to address swine operations. Colorado Regulation No. 2, Part B should not be included as a general condition in the operating permit.

The citation in General Condition 16 (open burning) was revised. The open burning requirements are no longer in Reg 1 but are in new Reg 9. In addition, changed the reference in the text from “Reg 1” to “Reg 9”.

Condition 17 (ozone depleting compounds) was revised to reflect updates made to Colorado Regulation No. 15.

The reference in Condition 28 (volatile organic compounds) to Regulation No. 7, Section III.C.3 was corrected to Regulation No. 7, Section VIII.C.3.

Added the requirements in Colorado Regulation No. 7, Section V.B (disposal of volatile organic compounds) to General Condition 28.

<u>Appendices</u>

First Page of Appendices – The phrase “except as otherwise provided in the permit” was added after the word “enforceable” in the disclaimer at the request of EPA.

Revised the description of the insignificant activity category for the emergency power generators (Reg 3, Part C, Section II.E.3.nnn) and added a category for stationary internal combustion engines (Reg 3, Part C, Section II.E.3.xxx). The equipment previously identified under Section II.e.3.nnn was divided as appropriate between the 2 sections.

Corrected Reg 3 citation for the insignificant activity category for storage tanks with annual throughput less than 400,000 gallons in Appendix A.

Appendix B and C were replaced with revised Appendices.

The EPA addresses in Appendix D were corrected.